U.S. EPA
UNDERGROUND INJECTION CONTROL
PERMIT

PREPARED: April 2009

Permit No. CO10460-01919

Class I Non-Hazardous Waste Disposal Well

Soute 32-11 #10-5
La Plata County, CO

Issued To
Red Willow Production Company
116 Mouache Drive
P.O. Box 737
Ignacio, CO 81137

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Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Red Willow Production Company
116 Mouache Drive
P.O. Box 737
Ignacio, CO 81137

hereby referred to as the "Permittee", is authorized to construct and operate the following Non-Hazardous Class I injection well or wells:

Soute 32-11 #10-5
1150 FSL & 1130 FWL, SWSW S10, T32N, R11W
La Plata County, CO

EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations (40 CFR §144.35).

This Permit is issued for 10 years from the Effective Date unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: JUN 24 2009 Effective Date JUN 24 2009

Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) recording devices capable of continuously monitoring, within a certified accuracy of 95% or better, the following:

  (i) injection pressure, flowrate, volume, and

  (ii) wellhead pressure readings from the tubing-casing; and

(b) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(c) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

  (i) on the injection tubing; and

  (ii) on the tubing-casing annulus (TCA); and

(d) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and

(e) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Postponement of Construction or Conversion

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

7. Annual Pressure Falloff Test

The operator must perform a pressure falloff test prior to authorization to inject and at least once every twelve months thereafter. The pressure fall-off test is required for Class I operations [40 CFR 146.13 (d)(1)] to monitor pressure buildup in the injection zone in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone and to aid in determining the lateral extent of the injection plume.

The operator is required to prepare a plan for running the yearly falloff test. EPA Region VI has developed a set of guidelines that should be used by the operator when developing their site specific plan. The Region VI "UIC Pressure Falloff Testing Guideline" is available from EPA and will be provided upon request. The final test plan shall be submitted to Region VIII for review at least 30 days prior to conducting the annual pressure falloff test.

Annual falloff tests must be performed within one week of the date of the previous falloff test. It is important that the initial and subsequent tests follow the same test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. The permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information on any reservoir boundaries, an estimate of the well skin effect and reservoir flow conditions. The report shall also compare the test results with the previous years test data and shall be prepared by a knowledgeable analyst.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

(a) There is no significant leak in the casing, tubing, or packer (Part I); and

(b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II).

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in APPENDIX B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. *Mechanical Integrity Test Methods and Criteria*

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. *Notification Prior to Testing.*

The Permittee shall notify the Director at least 30 days prior to any scheduled mechanical integrity test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. *Loss of Mechanical Integrity.*

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. *Requirements Prior to Commencing Injection.*

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-9 or 7520-12; all applicable logging and testing requirements of this permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Except during stimulation and performing required formation test(s), injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. Injection Volume Limitation.

Injection volume is limited to the total volume specified in APPENDIX C.

5. Injection Fluid Limitation.

Injected fluids are limited to: 1) Class II oil and gas related fluids. Class II fluids are brought to the surface in connection with oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). The well also may be used to inject approved Class II wastes brought to the surface such as drilling fluids and spent well completion, treatment and stimulation fluids. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved, and; 2) Non-hazardous industrial waste generated from a proposed experimental algae biofuels plant that receives waste fluids from coal bed methane production as input. These waste streams shall be nonhazardous at the time of injection. This means that they shall not meet the definition of a hazardous waste pursuant to 40 CFR 261.3 or exhibit any hazardous characteristics of ignitability, corrosivity, and/or toxicity.

6. Tubing-Casing Annulus (TCA)

The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency.

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. Monitoring Methods.

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Continuous monitoring of the injection pressure, annulus pressure, injection rate, and injected volumes shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Recordings should be made at least once every ten (10) minutes. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection and annulus pressures the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected.

(c) Injection pressure, annulus pressure, injection rate, and injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Quarterly Reports.

Whether the well is operating or not, the Permittee shall submit Quarterly Reports to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D. The report of fluids injected during the quarter must identify each new fluid source by well name and location, and the field name or facility name.

The operator shall also provide summary graphs covering the reporting period of the injection pressure, annulus pressure, and injection rate. Copies of the analytical results for the samples of injected fluids, and records of any major changes in characteristics or sources of injected fluid shall be included in the Quarterly Report.

The Quarterly Report shall cover the period from the January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Quarterly Reports shall be submitted by the 15th day of the month following the end of the data collection period. EPA Form 7520-8 may be copied and used to submit the Quarterly Report.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class I injection well to a non-Class I well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Duty to Reapply.
If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. Need to Halt or Reduce Activity Not a Defense.
It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate.
The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance.
The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions.
This Permit may be modified, revoked and reissued or teminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights.
This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information.
The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry.
The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.
All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The Soute 32-11 #10-5 well was drilled to a total depth (TD) of 8780'. The plug back total depth (PBTD) is 8740'.

Surface Casing: A 13.375" 54.5# K55 STC casing was set at 262' in a 17.5" hole and cemented to surface with 360 sx of Class B cement.

Intermediate Casing #1: A 9.625" 36# K55 STC casing was set at 3029' in a 12.25" hole and cemented to surface with 600 sx 50/50 Poz and 500 sx Class G cement. EPA review of the CBL shows that cement exists along the entire length of the casing. Operator states the TOC is 20'.

Intermediate Casing #2: A 7" 26# N80 LTC casing was set from 2788' to 7492' in a 8.75" hole and cemented with 600 sx 65/35 Poz, 130 sx Class G cement. EPA review of the CBL indicates the entire length of the casing was cemented.

Production Casing: A 4.5" 13.5# N80 LTC casing was set at 8780' in a 6.125" hole and cemented with 290 sx of Class G cement. EPA review of the CBL indicates cement coverage between 8300' to 7750' and becomes intermittent from 7500' to top of casing at 7277'. The daily report reported returns at the top of the liner.

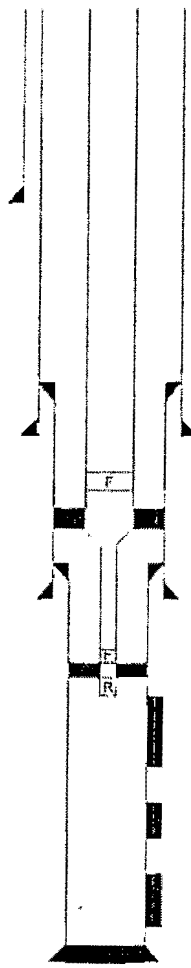
Perforations: Perforations have be made in the Morrison (7680'-7700' and 7850'-7860'), the Bluff (8254' to 8417'), and the Entrada (8589' to 8711').

Tubing and packer will be installed no higher than 100 feet of the top open perforation.

RED WILLOW PRODUCTION COMPANY

Formation Tops:

Dakota:	7436'
Dakota Confining.	7564'
Burro Canyon:	7580'
Morrison:	7670'
Bluff SS:	8212'
Todilto :	8558'
Entrada	8592'
Chinle:	8712'



EPA Permit # CO20460-001919
MAOP 1420 psi
MIR 3000 BWPD

HISTORY

6/01/07	Perforate Morrison, step rate test all horizons, MIT
5/28/03	Inspected WH and TBG Hanger
5/08/01	Pressure test Csg. Held 970 for 30 min
3/09/01	Squeezed casing leak in Morrison (7696'-7714')

13-3/8" 54.5# K55 @ 262' Cemented to surface

Tubing: 222 Jts of 3-1/2" 9.3#, J55 tubing (1 x 2' sub at top of string)
2.75" F Nipple above 7" packer @ 7219'KB
11 Jts of 2-3/8" 4.7# J55 tubing below 7" packer
1.81" F nipple 1 jt up @7555' KB
1 78" R nipple @ 7600' w/ mule shoe on bottom

9-5/8", 36#, K55 Csg @ 3029'. TOC =20' by CBL

7" Baker R-3 Compression Packer set @ 7228'
40,000 lbs set down on compression packer

7", 26# N80 Liner 2788'-7492' TOC = top of liner

4.5" Model D Paker @ 7591' w/6" Mill out extention below paker

Morrison.	7680' - 7700'	existing
	7850' - 7860'	existing
Bluff Perfs.	8254'-8417'	existing
Entrada Perfs	8569' - 8711'	existing

4-1/2" 13.5#, N80 Liner 7277' - 8780'
(Cement reportedly circulated to top of liner hanger,
CBL shows minimal coverage above 7600')
PBTD = 8740'

WELL INFORMATION

	Soute WDW 32-11 #10-5
WELL NAME	06/18/07
DATE	05-067-07123
API #	CURRENT
STATUS	T32N-R11E SECTION 10 1150' FSL 1130' FWL -
SURFACE LOCATION	T32N-R11E SECTION 10 1150' FSL 1130' FWL -
BOTTOM-HOLE LOCATION	La Plata County, CO
COUNTY, STATE	6252
GROUND ELEVATION	12'
KB-GR MEASUREMENT	
COMMENTS	

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APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.

Logs will be conducted according to current UIC guidance. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

NO LOGGING REQUIREMENTS

Tests.

Tests will be conducted according to current UIC guidance. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: Soute 32-11 #10-5

TYPE OF TEST	DATE DUE
Standard Annulus Pressure	Prior to authorization to inject and at least once every five (5) years after the last successful demonstration of Part I Mechanical Integrity.
Temperature Log	Prior to authorization to inject and at least once every five (5) years after the last successful demonstration of Part II MI.
Pressure Fall-Off Test	Prior to authorization to inject and at a minimum once annually. Annual falloff tests must be performed within one week of the date of the previous falloff test.
Injection Zone Water Sample	If the Burro Canyon is perforated, a representative sample (stabilized specific conductivity from 3 successive swab runs) from the injection zone will be analyzed for TDS, pH, Specific Gravity and Specific Conductivity, prior to authorization to inject.
Step Rate Test	If the Burro Canyon is perforate, a SRT shall be performed prior to receiving authorization to inject.

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
Soute 32-11 #10-5	1,420

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

The fracture gradient for the Burro Canyon is estimated. A step rate test will be required prior to injection into the Burro Canyon.

WELL NAME: Soute 32-11 #10-5

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Burro Canyon	7,580.00 -	7,655.00	0.625
Morrison	7,655.00 -	8,214.00	0.625
Bluff Sandstone	8,214.00 -	8,424.00	0.616
Entrada	8,572.00 -	8,712.00	0.722

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

The injection volume is limited to 43,596,500 barrels for the entire life of this injection well, which includes previously injected volumes. From July 1991 to February 28, 2009, 2,500,294 million barrels of waste fluid has been injected into the Soute 32-11 #10-5.

WELL NAME: Soute 32-11 #10-5

FORMATION NAME	MAXIMUM VOLUME LIMIT (bbls)
Burro Canyon	
Morrison	43,596,500.00
Bluff Sandstone	

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

CONTINUOUS MONITORING	Injection pressure (psig)
	Injection rate (bbl/day)
	Annulus pressure(s) (psig)
	Fluid volume injected (bbls)

QUARTERLY	
ANALYZE	Injected fluid Total Dissolved Solids (mg/l)
	Injected fluid Specific Gravity
	Injected fluid Specific Conductivity (umhos/cm)
	Injected fluid pH

QUARTERLY	
REPORT (EPA Form 7520-8)	Each month's minimum, average, and maximum injection pressures (psig)
	Each month's minimum, average, and maximum injection rate (bbl/day)
	Each month's minimum, average, and maximum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of quarterly injected fluid analysis
	Sources of all fluids injected during the quarter

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

Prior to plugging the well, run a Mechanical Integrity Test, pull tubing and packer, and repair any casing leaks.

At a minimum, the following plugs are required:

PLUG NO. 1: Set a cement retainer at approximately 7630' and pump and squeeze approximately 115 sx of cement to cover and squeeze perforations. Place cement on top of cement retainer to isolate Entrada, Dakota, 7" casing shoe, and 4.5" liner top from approximately 7630' to 7227'.

PLUG NO. 2: Set an approximately 100' balance plug inside casing across the Gallup top (estimated from 5525' to 5425').

PLUG NO. 3: Set an approximately 100' balance plug inside casing across the Mesaverde top (estimated from 4428' to 4328').

PLUG NO. 4: Set a balance plug above inside casing to cover the Pictured Cliffs top and the 9.625" casing shoe and 7" liner top (estimated from 3079' - 2715').

PLUG NO. 5: Set an approximately 100' balance plug inside casing across the Fruitland top (estimated from 2385' to 2285').

PLUG NO. 6: Set a surface plug to cover casing shoe to surface (estimated from 312' to surface').

NOTES:
Plug placement must be verified by tagging the top of the plug after the cement has had adequate time to set.

Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal should be used during plugging operations, and should remain between plugs in the well after cement plug placement.

Southern Ute WDW 32-11 #10-5

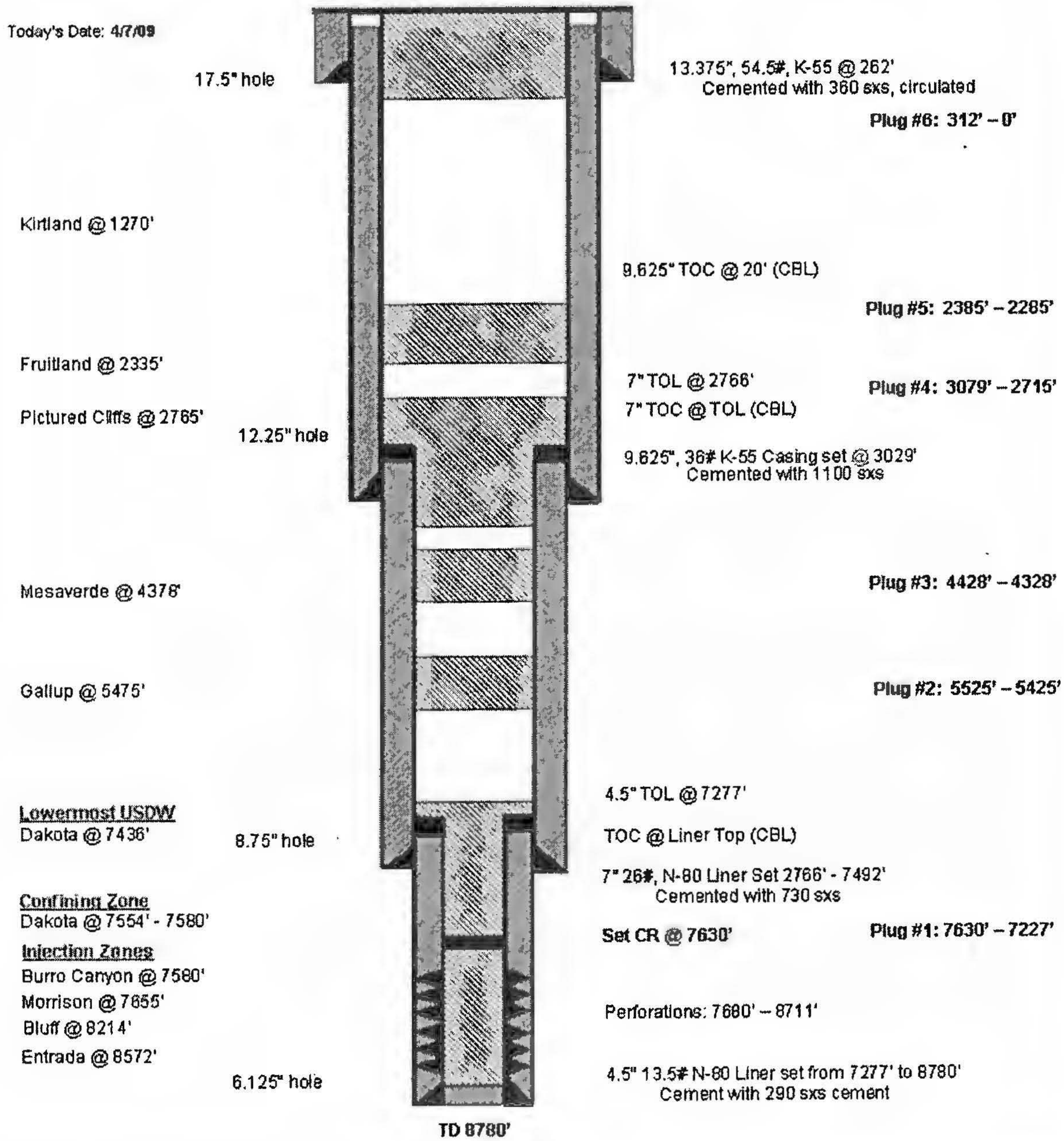
Proposed P&A

Ignacio Blanco

1150' FSL / 1130' FWL Section 10, T-32-N, R-11-W

La Plata County, CO, API #05-067-07123

Lat: 37.028249 N / Long: -108.034592 W



10460-01919_P&A_SoUte32-11-10-5.jpg

STATEMENT OF BASIS

RED WILLOW PRODUCTION COMPANY
SOUTE 32-11 #10-5
LA PLATA COUNTY, CO

EPA PERMIT NO. CO10460-01919

CONTACT: Wendy Cheung
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6242

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the operation of injection well or wells governed by the conditions specified in the Permit. The Permit is issued for 10 years unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41.

PART I. General Information and Description of Facility

Red Willow Production Company
116 Mouache Drive
P.O. Box 737
Ignacio, CO 81137

on

March 12, 2009

submitted an application for an Underground Injection Control (UIC) Program Permit to construct and operate the following Class I injection well or wells:

Soute 32-11 #10-5
1150 FSL & 1130 FWL, SWSW S10, T32N, R11W
La Plata County, CO

Regulations specific to Southern Ute Indian Reservation injection wells are found at 40 CFR 147 Subpart G.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

Red Willow Production Company (RWPC) proposes to convert an existing Class II disposal well into a Class I non-hazardous well in the Ignacio Blanco Field, La Plata County, Colorado. Soute 32-11 #10-5 well is presently used for the disposal of water produced from the RWPC's coal seam production wells and water derived from the compression of the methane gas. RWPC proposes to include non-hazardous industrial waste generated from a proposed experimental algae biofuels plant that will be operated by Solix Biofuels Inc., who have entered into a joint venture with RWPC.

PERMIT HISTORY

The original UIC permit COS2460-1919 was issued to McKenzie Methane Corporation on January 4, 1989. The well name at that time was Walker 5-10 WDW. Below is a history of the permit modifications since the date of issuance:

* Minor Modification No.1 was issued on February 9, 1989 to move the well location 100 feet from its original location.
* Major Modification No.1 was issued on April 10, 1989 to modify the injection zones from the Animas and Kirtland formations into the deeper Morrison, Burro Canyon, Bluff, and Entrada formations and associated construction and P&A changes. Aquifer exemptions were granted for portions of the Burro Canyon, Bluff and Morrison formations on June 13, 1989.
* Authorization to inject was issued on September 18, 1990.
* Minor Modification No.2 was issued on May 12, 1994 to increase the Maximum Allowable Injection Pressure (MAIP) to 2425.
* Major Modification No.2 was issued on May 28, 2004 that 1) transferred the permit to RWPC, 2) changed the permit number to CO20460-01919, 3) modified the authorized injection and confining zones, 4) modified permit to allow injection into all 4 formations, 5) modified the Part I and Part II mechanical integrity requirements, 6) required Step Rate Test to be conducted to establish new MAIP, and 7) clarified compliance reporting. To be consistent with the modification of the

authorized injection intervals, the vertical limits of the aquifer to be exempted were also modified.
* Minor Modification No.3 was issued on May 22, 2008 to decrease the MAIP to 1420 based on the results of step rate tests conducted in June 2007.
* Minor Modification No.4 was issued on October 28, 2008 to include as authorized injectate, water derived from compression of methane gas from the RWPC's coal seam production wells

The existing permit allows injection into the Entrada, Bluff, Morrison, and Burro Canyon Formations. Aquifer exemptions have been issued for portions of the Bluff, Morrison, and Burro Canyon Formations.

This Permit is issued for 10 years from the Effective Date unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Southern Ute Indian Tribe or the State of Colorado unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

CONVERSION WELLS

Well Name	**Well Status**	**Date of Operation**
Soute 32-11 #10-5	Conversion	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

The well is located in the Ignacio Blanco Field in the northern part of the structural and sedimentary San Juan Basin. The primary geologic structure is a northeast trending hogback that formed through erosion of a monocline. The geologic formations known as the Pictured Cliffs Sandstone, Fruitland Formation, and Farmington Sandstone define the hogback. Considerable variability exists within some of these units, ranging through clay, silt, and sand. These differences affect topography as the more resistive sandstones developed into ridges while the shale and coal layers eroded to form valleys.

In the area, the most important natural gas producing formations include the Fruitland, Pictured Cliffs, Mesa Verde, Dakota and Paradox formations. Production comes from the the unconventional Fruitland coal-seam reservoirs as well as the deeper formations, such as the conventional Pictured Cliffs, Mesa Verde, Dakota and Paradox formations.

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
Soute 32-11 #10-5

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Nacimiento	0	888	< 10,000	shale, siltstone, and sandstone
Animas	888	1,270	< 10,000	andesite boulder & pebbles, interbedded with sandstone & shale
Kirtland	1,270	2,335	< 10,000	shale
Fruitland	2,335	2,765	< 10,000	coal/sandstone/shale
Pictured Cliffs.	2,765	2,995	< 10,000	sandstone
Lewis	2,995	4,378	< 10,000	shale
Mesa Verde	4,378	4,718	< 10,000	coal/sandstone/shale
Cliff House	4,718	4,822	< 10,000	sandstone
Menefee	4,822	5,130	< 10,000	coal/sandstone/shale
Point Lookout	5,130	5,475	< 10,000	sandstone
Mancos	5,475	7,278	< 10,000	shale
Green Horn	7,278	7,362	< 10,000	siltstone
Graneros	7,362	7,436	< 10,000	sandstone/shale
Dakota	7,436	7,554	< 10,000	sandstone
Dakota Confining	7,554	7,580	< 10,000	sandstone with traces of coal
Burro Canyon	7,580	7,655	< 10,000	sandstone with traces of coal
Morrison	7,655	8,214	8,513	sandstone/shale/mudstone
Bluff Sandstone	8,214	8,424	48,700	sandstone
Summerville	8,424	8,559		shale/siltstone
Todilto	8,559	8,572		limestone/shale
Entrada	8,572	8,712		sandstone
Chinle	8,712			shales/mudstones

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The application proposes to inject into the Burro Canyon, Morrison, Bluff, and Entrada Formations. Aquifer exemptions have been issued for portions of the Bluff, Morrison and Burro

Canyon Formations where injection is authorized.

The Burro Canyon Formation consists of chert-pebble conglomerate and grayish-green shale with light-brown sandstone lenses. The formation is of the Cretaceous Age and approximately 75 feet thick. To date, the Burro Canyon Formation has not been perforated. The porosity is estimated to be between 5%-7%. A step rate test will be required and a water sample obtained prior to injection, should this zone be used for disposal.

The Morrison is composed of sandstones interbedded with shales. The shales are typically light to medium green and light to medium gray while the sandstones range from clear to white and light to medium green in color. The formation is of the Jurassic Age and approximately 559 feet thick. During the step rate test, the formation did not fracture. The calculated fracture gradient is 0.625 psi/ft using the highest pressure achieved during the test. The porosity is estimated to be between 2%-4%. A water sample taken in May 2007 from the formation showed that the TDS to be 8,513 mg/L. An aquifer exemption has been granted for this formation.

The Bluff Formation consists of medium grained eolian sandstone. The formation is of the Jurassic Age and approximately 210 feet thick. The fracture gradient is 0.616 psi/ft from step rate test results. The porosity is estimated to be between 3%-4%. An April 1990 water sample from the formation analyzed for TDS was 48,700 mg/L. Based on this sample, the formation at this location is not a USDW and an aquifer exemption is not required, although one has been provided for the Bluff formation.

The Entrada Formation consists of light gray, cross-bedded sandstone. The formation is of the Jurassic Age and approximately 140 feet thick. Step rate test results show the fracture gradient is 0.722 psi/ft. The formation was swabbed in April 1990, but no measurable amount of fluid could be obtained and a water analysis was not performed.

TABLE 2.2
INJECTION ZONES
Soute 32-11 #10-5

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Burro Canyon	7,580	7,655	< 10,000	0.625		P
Morrison	7,655	8,214	8,513	0.625	2.00%	P
Bluff Sandstone	8,214	8,424	48,700	0.616		P
Entrada	8,572	8,712		0.722		N/A

*** P - Currently Exempted**
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

A 26 feet shale layer has been identified adjacent to the Burro Canyon top in the Dakota Formation to serve as the confining zone. The Dakota Formation consists of sandstones interbedded with shales.

The next confining layer above the injection zones is the Mancos Shale. It is a substantial marine shale interval with sparse interbedded sandstone and limestone, approximately 1800 feet thick.

TABLE 2.3

CONFINING ZONES

Soute 32-11 #10-5

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Dakota Confining	sandstone with traces of coal	7,554	7,580

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

The Nacimiento Formation is a heterogeneous nonmarine formation composed of shale, siltstone, and sandstone

The Animas Formation consists of boulders and pebbles of andesite in tuffaceous matrix, interbedded with variegated shale and sandstone.

The Kirtland Formation is divided into a lower shale, the Farmington Sandstone member which consists of sandstone, light gray, fine to medium grained, massive, interbedded with siltstone and shale, and an upper shale member

The Fruitland Formation consists of varying proportions of interbedded sandstone, shale, and coal, with fine- to medium-grained sandstone beds, which are gray, brown, and olive in color, and grade laterally and vertically into shales and siltstones. The upper sandstone beds are well indurated and form resistant ledges.

The Pictured Cliff consists of sandstones interbedded with some thin shale beds. The lower zone consists of fine grained sandstone interbedded with small amounts of gray shale and siltstone. The upper zone is primarily medium- to thick-bedded sandstone.

The Mesa Verde Group consists of the Cliff House Sandstone, Menefee, and Point Lookout Sandstone Formations:

The Cliff House Sandstone Formation consists of gray, calcareous, marine sandstone, and silty shale that is crossbedded and massive in places. The sandstone is very fine to fine grained and well sorted.

The Menefee consists of a series of interbedded lenses of sandstone, siltstone, shale and coal. The sandstones and sandstones and siltstones are various shades of light gray and yellowish gray. The shales are mostly dark gray or brown. Thin coal beds occur throughout the formation.

The Point Lookout Sandstone Formation consists of light-gray to brown marine sandstone, and is massive and cliff-forming. The formation contains interbedded siltstone and shale in the lower part.

The Dakota Sandstone is composed of white, light- to medium-gray, and yellowish-brown conglomeratic sandstone, fine- to coarse-grained sandstone, and conglomerate interbedded with dark- to medium-gray siltstone, carbonaceous shale, and thin coal beds. Conglomeratic clasts in the Dakota Sandstone usually consist of chert and quartz pebbles.

TABLE 2.4

UNDERGROUND SOURCES OF DRINKING WATER (USDW)

Soute 32-11 #10-5

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Nacimiento	shale, siltstone, and sandstone	0	888	< 10,000
Animas	andesite boulder & pebbles, interbedded with sandstone & shale	888	1,270	< 10,000
Kirtland	shale	1,270	2,335	< 10,000
Fruitland	coal/sandstone/shale	2,335	2,765	< 10,000
Pictured Cliffs	sandstone	2,765	2,995	< 10,000
Lewis	shale	2,995	4,378	< 10,000
Mesa Verde	coal/sandstone/shale	4,378	4,718	< 10,000
Cliff House	sandstone	4,718	4,822	< 10,000
Menefee	coal/sandstone/shale	4,822	5,130	< 10,000
Point Lookout	sandstone	5,130	5,475	< 10,000
Mancos	shale	5,475	7,278	< 10,000
Green Horn	siltstone	7,278	7,362	< 10,000
Graneros	sandstone/shale	7,362	7,436	< 10,000
Dakota	sandstone	7,436	7,554	< 10,000

Exempted Aquifer(s) (40 CFR 144.7 and 146.4)

Aquifers exempted from protection as a USDW are listed in TABLE 2.5. Exempted is that portion of the aquifer between the depths listed ("TOP" and "BASE") and within the Exempted Radius of the well's surface location, or for an Area Permit, one-quarter (1/4) mile exterior to the defined Area Permit boundary. "Criteria" corresponds to the appropriate criteria (below) for exemption. "VOLUME" is the maximum volume of fluid which can be injected into the exempted area before the injected fluids exceed the exemption boundary, calculated using the following formula:

$$V = Pi * radius2 * height * porosity / 5.615$$

where V = VOLUME (in barrels)
Pi = 3.1416
radius2 = Exempted Radius (squared) - generally 1/4 mile

height = height of reservoir ("BOTTOM" - "TOP")
porosity = reservoir porosity (in percent)
5.615 = conversion factor (cubic feet per barrel)

The Statement of Basis (SOB) for the Major Modification #1 dated March 23, 1989 states that basis for exemption are (a) and (c) in the criteria described below. The SOB also stated that the Entrada formation is not classified as an USDW and therefore did not require an aquifer exemption. Aquifer exemptions for portions of the Burro Canyon, Morrison and Bluff were issued on June 13, 1989.

Under Major Modification #2, the vertical intervals were modified to be consistent with the modified authorized injection intervals. The portions of the formations that were exempted, extend ½ mile from the well bore, for these intervals:

The Burro Canyon is exempted from 7580'-7655'
The Morrison is exempted from 7680'-8212'
The Bluff is exempted from 8212'-8592'

TABLE 2.5
AQUIFER EXEMPTION
Soute 32-11 #10-5

Formation Name	Top (ft)	Base (ft)	Criteria	Volume (bbl)
Burro Canyon	7,580	7,655	c	
Morrison	7,655	8,214	c	43,596,500
Bluff Sandstone	8,214	8,424	c	

An aquifer or a portion thereof may be determined to be an "exempted aquifer" provided it meets criteria, listed below.

a It does not currently serve as a source of drinking water; AND

b(1) It cannot now and will not in the future serve as a source of drinking water because it is mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible; OR

b(2) It cannot now and will not in the future serve as a source of drinking water because it is situated at a depth or location which makes recovery of water for drinking water purposes economically or technically impractical; OR

b(3) It cannot now and will not in the future serve as a source of drinking water because it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; OR

b(4) It cannot now and will not in the future serve as a source of drinking water because it is located over a Class III well mining area subject to subsidence or catastrophic collapse; OR

c The total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
Soute 32-11 #10-5

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	17.50	13.38	0 - 262	0 - 262
Intermediate	12.25	9.63	0 - 3,029	20 - 3,029
Intermediate	8.75	7.00	2,788 - 7,492	2,788 - 7,492
Longstring	6.13	4.50	7,277 - 8,780	7,277 - 8,780

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)
The constuction of this "existing" injection well was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for "existing" injection well or wells are shown in TABLE 3.1.

Casing and Cementing (TABLE 3.1)
The construction plan for the well proposed for conversion to a Class I injection well was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction and conversion details for the well are shown in TABLE 3.1.

Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)
The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for continuous monitoring of injection pressure, flowrate, volume, and annular pressure. In addition, it is necessary to have a mechanism to access the wellhead and injection line to obtain manual measurements of injection and annulus pressures and samples of the injection fluid. Required equipment must include: 1) continuous recording devices for injection pressure, flowrate, volume and annular pressure; 2) shut-off valves located at the wellhead on the injection tubing; 3) a flow meter that measures the cumulative volume of injected fluid; 4) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressures; and 5) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

Area Of Review

Applicants for injection well permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

There are 6 wells in the 1/2 mile area of review, however only one was drilled to a depth that penetrates the confining layer interval in the Dakota at 7554'-7580'. The Soute 32-11 #10-1 well is located approximately 75 feet southwest from the proposed Class I well. It was drilled to a total depth of 7641' and plugged back to 5550' and cased. A 100 sx plug was placed from 7588' to 7159'.

The nearest water well is a 200 feet irrigation well over a one mile away from the injection well.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

TABLE 4.1 lists the wells in the AOR, and shows the well type, operating status, depth, top of casing cement and whether a CAP is required for this well.

No corrective action is needed for the injection well or wells in the AOR.

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES
Soute 32-11 #10-5

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Burro Canyon	7,580	0.625	1,405
Morrison	7,655	0.625	1,420
Bluff Sandstone	8,241	0.616	1,455
Entrada	8,572	0.722	2,425

Approved Injection Fluid

Approved injected fluids are limited to:

1) those fluids which are brought to the surface in connection with oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). The well also may be used to inject approved Class II wastes brought to the surface such as drilling fluids and spent well completion, treatment and stimulation fluids. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved and,

2) non-hazardous industrial waste generated from a proposed experimental algae biofuels plant that receives waste fluids from coal bed methane production as input. These waste streams shall be nonhazardous at the time of injection. This means that they shall not meet the definition of a hazardous waste pursuant to 40 CFR 261.3 or exhibit any hazardous characteristics of ignitability, corrosivity, and/or toxicity.

Prior to the injection of any additional waste streams, the Permittee shall notify the EPA to receive prior approval from the Director. This well is NOT approved for commercial brine or other commercial fluid disposal operation.

Injection Pressure Limitation

Except during stimulation and performing required formation test(s), injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in injection zone(s).

Based on step rate tests performed in June 2007, the MAIP is set at 1420 psi. The Morrison formation did not fracture at the pressures tested, however using the maximum pressure achieved during the test (4800 psi), the calculated fracture gradient is 0.625 psi/ft providing for an MAIP of 1420 psi. The fracture gradient of the Bluff formation is 0.616 psi/ft or MAIP 1450 psi. The Entrada fracture gradient was determined to be 0.722 psi/ft or MAIP 2420 psi. All three intervals will be opened and injected into simultaneously and therefore the smallest of the three values will be used, 1420 psi.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit,

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Based on sampling data, the only formation known to be a USDW is the Morrison (although the Burro Canyon and Bluff have also been exempted). The fill up volume for the Morrison was calculated to determine the injection volume limit such that fluids stay within the exempted area, a radial distance of ½ mile from the well bore. This has been calculated to be 43,596,500 barrels. This calculation assumes that the entire volume out to a ½ mile from the well bore will be filled. It is unlikely that the entire Morrison interval will take water. However, the Bluff and Entrada are also receiving fluids and limiting the volume to calculated fill up volume for the Morrison is a reasonable estimation. The injection volume is limited to the 43,596,500 barrels for the Soute 32-11 #10-5 well injection well, which includes previously injected volumes. Since injection activities started, a little over 2.5 million barrels of waste fluid has been injected into this well.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Part I (Internal) MI will be demonstrated prior to beginning injection and at least once every five (5) years after the last successful demonstration of Part I MI. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing, or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, whichever is less, with ten (10) percent or less pressure change over thirty (30) minutes.

The analysis of the cement bond long (CBL) did not show adequate cement exists behind pipe to prevent significant movement of fluid out of the approved injection zone of the annulus cement, i.e., 80% bond index cement bond across the confining zone. Part II (External) MI will be demonstrated prior to beginning injection and at least once every five (5) years after the last successful demonstration of Part II MI. Part II MI shall be demonstrated by performing a Temperature Survey.

Annual Falloff Tests (40 CFR 146.13 (d)(1))

The pressure fall-off test is required for Class I operations and must be performed at least once every twelve months for the purposes of monitoring pressure buildup in the injection zone in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone and to aid in determining the lateral extent of the injection plume.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

Quarterly, the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, specific gravity, and any additional constituents specified in APPENDIX D of the Permit. This analysis shall be reported to EPA as part of the Quarterly Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Continuous monitoring of the injection pressure, annulus pressure, injection rate, and injected volumes shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Recordings should be made at least once every ten (10) minutes. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection and annulus pressures the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected. Monthly averaged, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure is required to be reported as part of the Quarterly Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Financial Statement, received February 9, 2009

Evidence of continuing financial responsibility is required to be submitted to the Director annually.